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Experimental Study to Find Optimum Pressure for Separation of Wellhead Fluids

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Abstract

The oil industry deals with wellhead fluids which are a mixture of hydrocarbons, water and impurities. In a two-phase separator design, the gas and liquid phases of a fluid stream are separated at a specific temperature and pressure. A proper separator design is important, because a separation vessel is normally the initial processing vessel in the surface facilities. Improper design can bottleneck and reduce the capacity of the entire facilities. The optimum separator pressure is defined as the pressure at which the maximum liquid volume is accumulated in the stock tank per volume of the feeded reservoir fluid.

The objective of this study is to find the optimum pressure in a single stage separation for the oil that was sampled from a well head at 300 psia by a “flash equilibrium separator”. This type of sampling technique enables to determine gas-oil ratios and shrinkage by a flash liberation or vaporization method. A bottom hole or recombination sample is expanded from above its bubble point pressure into a chamber which is equipped with a back pressure and temperature controller. The volume of gas liberated is measured with a gas meter at the atmospheric condition while the liquid volume is measured in the separator chamber. Then the liquid is drained and its gravity is measured.

In this paper, by using the “flash equilibrium separator”, “gasometer” and “densimeter” apparatuses, the optimum pressure for an Iranian oil sample is obtained and also the gas-oil ratio, oil formation volume factor and residual oil gravity are depicted all as a function of the separator pressure at the desired temperature.

Introduction

Well-head fluids which require separation may consist of a gas phase and a liquid phase, a gas phase and a solid phase, two immiscible liquid phases (oil and water), a gas phase and two liquid phases or any combination of these phases. The term “two-phase separator” is used in the oil and gas production industry to refer to a device used to separate a gas phase and a liquid phase [1, 3].

The oil and gas industry deals with well head fluids which are a mixture of hydrocarbons, water and impurities. As the stream flows from the reservoir to the surface it experiences pressure and temperature

changes. The physical character of the well stream changes with the lighter hydrocarbons tendency to evolve from the liquid phase to the gas phase and the heavier hydrocarbons tendency to evolve from the gas to the liquid phase. The following phenomena in the tubing cause turbulence so that the phases are constantly mixed: Due to the mixing action, the gas phase contains suspended liquid droplets and the liquid phase contains gas bubbles [2, 5].

Operating conditions of separators include temperature, composition of crude oil, and pressure. As the number of separators between wellhead and stock tank is increased, a higher amount of producing oil and the better quality of oil will be obtained. In another word, with more separators, producing oil is better from the point of view of quality and quantity. Each factor mentioned above is explained below and its effect is taken into consideration [2, 4, 5].

Temperature

Temperature does have a significant effect on the oil recovery. It has an effect of 2 to 7 percent to adjust the separator temperature at the optimum temperature. It is not economical to use several coolers and heaters in field to adjust the optimum temperature [2, 3, 6].

Composition

The composition of crude oil entering the separators cannot be changed, so the composition is not an adjustable parameter.

Pressure

Pressure is the only parameter that is adjustable to optimize the oil recovery. By establishing an optimum pressure by means of hydraulic control valves, vaporization of light hydrocarbons is prevented and reaches a minimum value [4]. This minimum value results in increasing the amount of oil in the stock tank, which helps to have better oil quality that is considerably more valuable.

Various methods are used to remove light components from a hydrocarbon liquid. The most common method is stage separation before the oil enters a stock tank or pipe line [5]. Operating conditions are stabilized to separate the gas from the well stream at the optimum pressure so as to introduce efficient mechanical separation within the separator and thereby produce a more stabilized flow of crude oil to the stock tank [6].

The most common method of separating oil and gas, termed multistage separation, involves a series of separators. The liquid leaving each separator is at its bubble point pressure, and the liquid's vapor pressure is the same as the separator operating pressure at the separation temperature. As the liquid reduces in pressure, hydrocarbon vapors are formed. The amount and composition of these hydrocarbon liquids and vapors can be determined by running flash calculations at various conditions. Because of the multi-component nature of the produced fluid, the higher pressure at which the initial separation takes place the more liquid will be obtained in the separator. This liquid contains some light components that vaporize in the stock tank downstream of the separator. If the pressure for the initial separation is too high, too many light components will stay in the liquid phase at the separator and be lost to the gas phase at the stock tank. If the pressure is

too low, fewer of these light components will be stabilized into the liquid at the separator and be lost to the gas phase [3, 7, 8].

This phenomenon can be calculated by using flash equilibrium techniques. The qualitative understanding of this phenomenon is important. The tendency of any component in the process stream to want to flash to the vapor phase depends on its partial pressure. The partial pressure of a component in a vessel is defined as the number of molecules of that component in the vapor space divided by the total number of molecules of all components in the vapor space times the pressure in the vessel. Since the partial pressure of a component is a function of the system pressure, an increase in the system pressure will increase the component's partial pressure. The increase in partial pressure reduces the component's equilibrium constant, and the molecules of that component tend toward the liquid phase. As the separator pressure is increased, the liquid flow rate out of the separator increases [5, 8, 9].

The problem with this process is that many of these molecules are the lighter hydrocarbons (methane, ethane, and propane), which have a strong tendency to flash to the gas state at stock tank conditions (atmospheric pressure). In the stock tank, the presence of a large number of light hydrocarbon molecules results in an increased tendency of intermediate-range hydrocarbons (butanes, pentane, and heptane) to flash. Thus, by keeping the lighter molecules in the feed to the stock tank, a small amount of them is captured as liquids, but the gas phase loses many more of the intermediate-range molecules. This is why, beyond some optimum point, there is actually a decrease in stock tank liquids if the separator operating pressure increases.

The fluid normally flows from the wellhead to production separators, where the gas is separated from the oil. The oil is then transferred to stock tanks for storage. The gas is normally gathered and sent to a gasoline plant, where it is processed into heavy components and residue gas, which is either injected to the reservoir or sold [9, 10].

The separator condition is one of the most important factors that control the gas-oil ratio, oil shrinkage, oil gravity, and gas gravity. The separator condition will be determined for given oil and its reservoir conditions in the next sections.

Description of Apparatus

The equipment used for the laboratory method for obtaining the optimum pressure is shown schematically in Fig. 1.

The “equilibrium flash separator” is an instrument designed to aid in determinations of the gas-oil ratio, relative volume, residual oil gravity, and related information on bottom hole or recombination samples. Optimum separator conditions are investigated by use of the flash liberation method. The instrument consists of a separator chamber equipped with a micrometer needle valve inlet and a drain valve. The chamber, with a volume of approximately 50 cc, is connected through stainless steel tubing and fittings to a pressure gage and a back pressure regulator which can be isolated with a cut-off valve.

A “gasometer” is used for accurate volumetric measurement of atmospheric gas in the PVT laboratory. The gasometer consists of two Pyrex chambers which can be used separately or as a single volume.

The digital density meter simplifies the accurate determination of the density of liquids and gases by reducing the procedure to the electronic measurement of a time period from which the density is automatically calculated by a built-in arithmetic processor. The measuring principle of the instrument is based on the change of the natural frequency of a hollow oscillator when filled with different liquid or gases.

The frequency of the oscillator is only influenced by that fraction of the volume of liquid or gas which is actually in the vibrating part of the sample tube.

Experimental Procedure

A. Live Oil Sampling and Preparation

For sampling live oil from the well head, the sample holder should be filled with water and pressurized to the well head pressure. This is done for preventing liberation of gas from the live oil before accumulation in cylinder. In the pipeline from the well head, the oil and gas are flowing simultaneously; that is, the well fluid is in the two phase state. Hence samples must be collected from the lower part of the line in order to collect only the liquid part of the fluid flowing through the pipeline.

When the sample container was transported to the laboratory, it was observed that there was a noticeable volume of gas on the top of the cylinder. The fluid that is used for the purpose of flash equilibrium tests must be only in the liquid state. For preparing the single phase, the cylinder should be holding on a roller system and start to rotate for some while to dissolve the free gas in the liquid phase.

B. Optimum Pressure Tests

The optimum pressure tests start with charging certain pressurized oil to the separator and allow to be stabilized in the separator. The back pressure regulator is adjusted at the desired pressure. By connecting the separator (graduated cylinder) to the gasometer, the volume of gas that liberated from the oil sample can be measured.

The back pressure regulator for the desired pressure is adjusted. While removing the liquid phase from the separator to the atmospheric pressure, the cylinder is connected to a gasometer to measure the gas volume liberated from oil at the atmospheric pressure. At the end of the test, the volume of gas is measured from the gasometer and the volume of the oil is measured in the atmospheric cylinder. After that, the oil formation volume factor and solution gas-oil ratio are calculated. The density of oil is also measured by the “digital density meter” to calculate the API gravity. Tests are conducted for different pressures while other operational conditions are kept fixed.

Results and Discussion

For different separator pressures, different volumes of gas and oil were observed and the density of oil was different due to intermediate components that exist in or leave the liquid phase at different separator pressures. The tests have been carried out at 50, 75, 100, 125, 150, 175, 200, 225, and 250 psi.

Table 1 shows results of flash tests for nine different pressures. For each test, the oil formation volume factor, solution gas-oil ratio and API gravity were calculated to obtain the optimum pressure.

Fig. 2 shows a plot of the oil formation volume factor versus the separator pressure. The oil formation volume factor at 125 psi is the minimum value. It shows that the oil production at this pressure is the maximum and, of course, this pressure is the optimum pressure.

The trend of the solution gas-oil ratio of produced oil versus pressure was plotted in Fig. 3. The solution gas-oil ratio is the minimum value at 125 psi. It shows that the value of gas and intermediate components liberated from oil is minimum rather than other value at different pressures. It also shows that the

intermediate components have been kept in the liquid phase due to phase equilibrium at the optimum pressure.

At the optimum pressure the maximum amount of intermediate components will stay in the produced oil at standard conditions where the oil density decreases and the API gravity of oil increases. Fig. 4 shows a plot of the API gravity versus the separator pressure in different tests. The maximum value of the API gravity was obtained at the optimum pressure, which shows the better quality of produced oil.

Conclusions

The following conclusions can be drawn from the experimental results presented above:

1. If in the field all separators are optimized in terms of pressure, a considerable increase in oil production will be observed and quality of the oil will be improved.
2. For the oil sampling from the well head, the two-valve cylinder should be filled with water and pressurized to the well head pressure to prevent gas liberation and then connected to flow line. When connected, the drain valve is partially opened to drain the water to minimize solution gas liberation in the cylinder.
3. In Iran, many production units burn associated gas as a flare. If an improper separator pressure is selected for the operating separators, the heavier components will vaporize. These components result in lots of smokes that can cause severe environmental issues.

Nomenclature

B_o	=	Oil formation volume factor, bbl/STB
P	=	Pressure, psi
API	=	Oil gravity
R_s	=	Solution gas-oil ratio, SCF/STB
ρ_o	=	Oil density, gr/ml

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Table 1 - The results of flash test for nine different pressures

$P_{seperator},$ <i>psi</i>	$V_{injected},$ <i>ml</i>	$V_{produced},$ <i>ml</i>	B_o	R_s	API^o
50	50	41	1.22	550.1	29.35
75	50	41.7	1.2	535.3	29.5
100	50	42.4	1.18	520.4	29.75
125	50	43.5	1.15	512.5	29.9
150	50	42.7	1.17	514.9	29.7
175	50	42	1.19	528.2	29.5
200	50	41	1.22	541.1	29.25
225	50	40	1.25	553.2	29.05
250	50	39.4	1.27	564.7	28.9

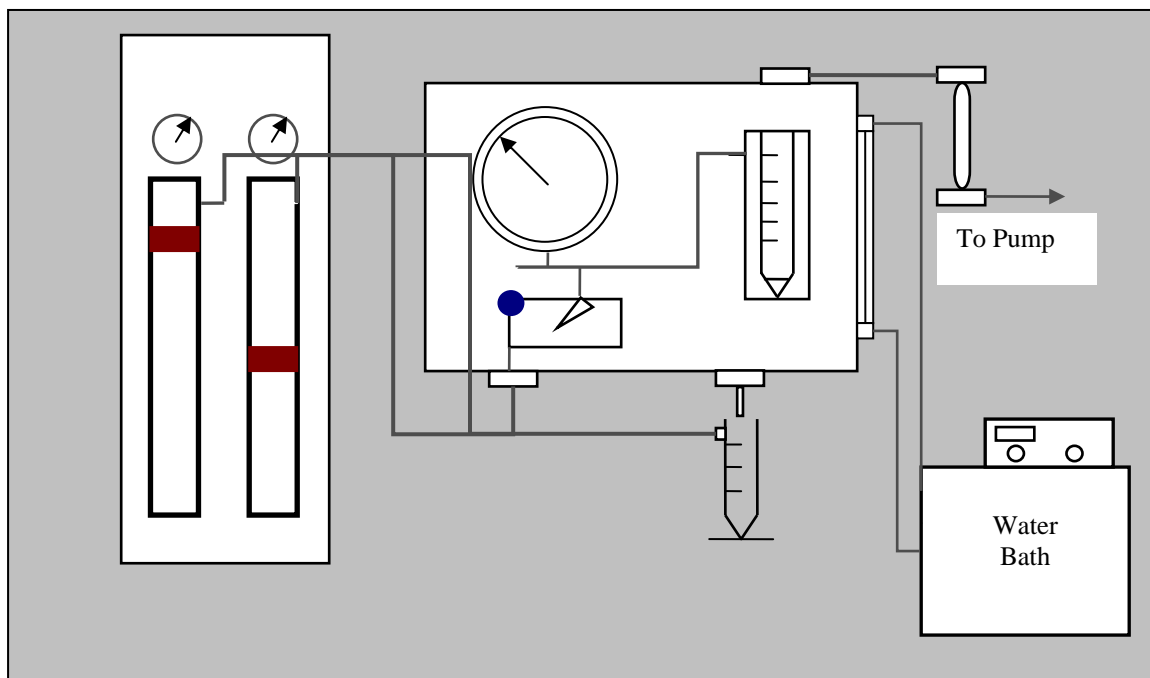


Fig. 1 - "Equilibrium Flash separator" apparatus

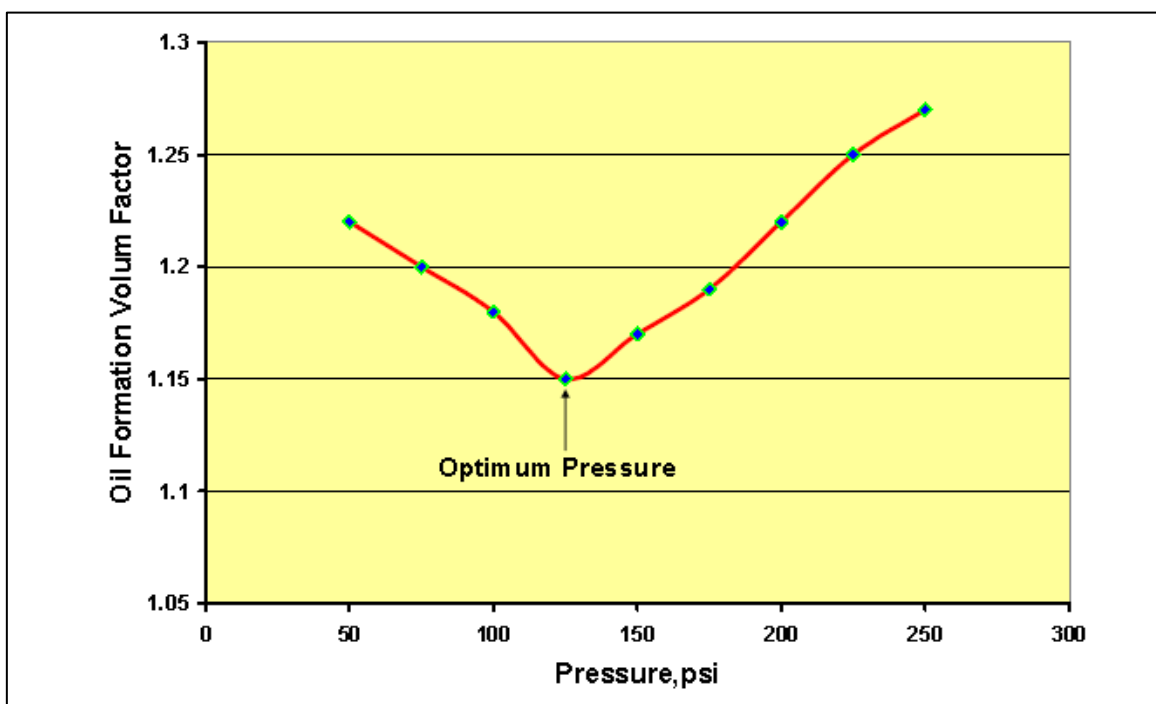


Fig. 2 - Oil formation volume factor versus separator pressure

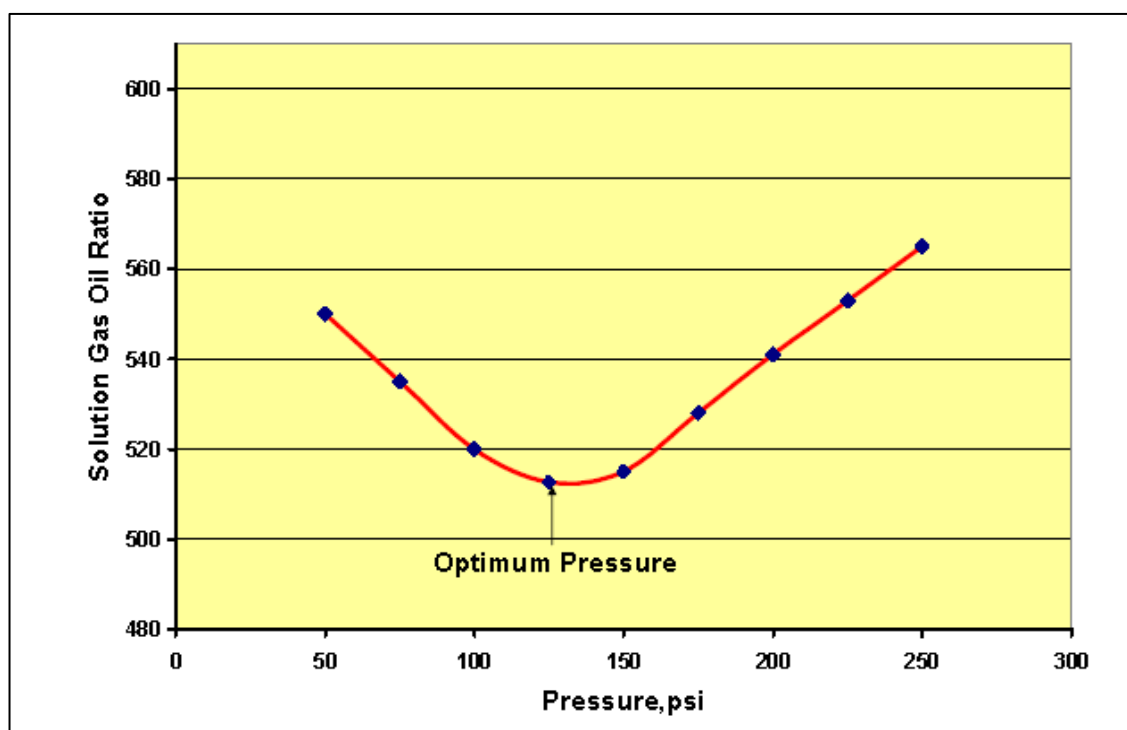


Fig. 3 - Solution gas oil ratio versus separator pressure

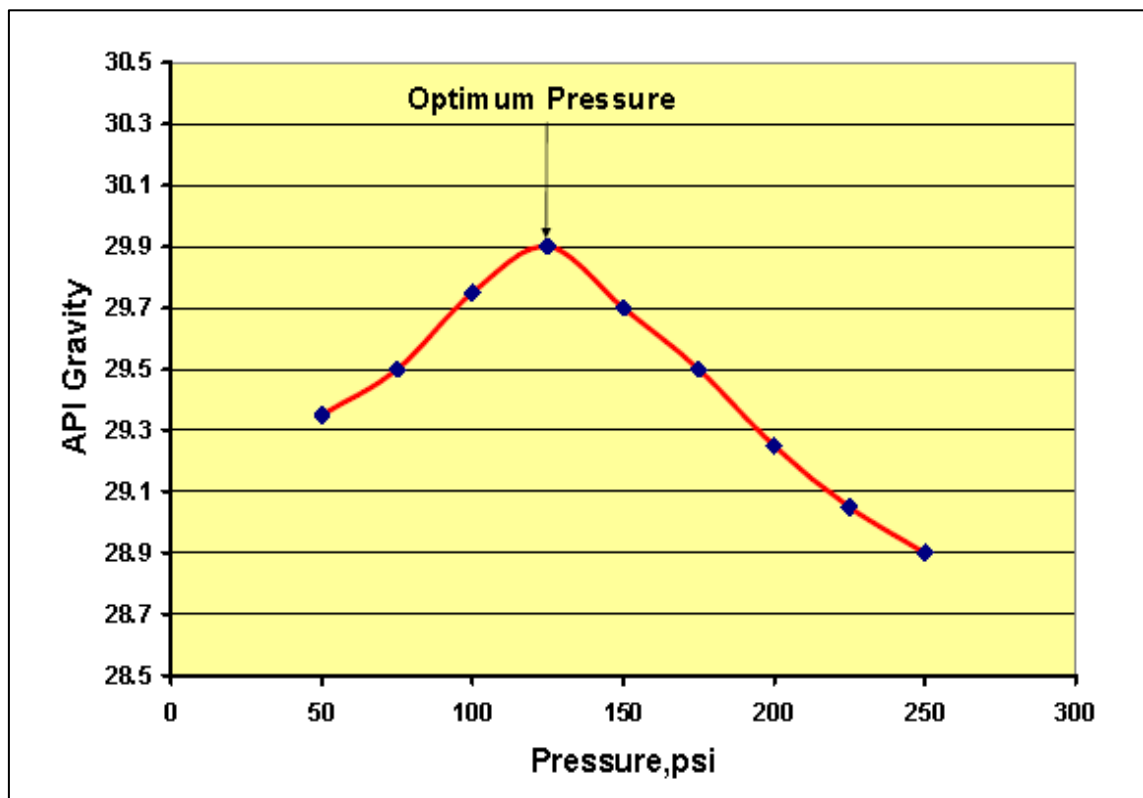


Fig. 4 - Oil gravity, API^o versus separator pressure